

# IMPLEMENTATION TEAM MEETING NOTES

**August 1, 2002, 9:00 a.m.-4 p.m.**

**NATIONAL MARINE FISHERIES SERVICE OFFICES  
PORTLAND, OREGON**

## ***I. Greetings, Introductions and Review of the Agenda.***

The August 1, 2002 meeting of the Implementation Team, held at the National Marine Fisheries Service's offices in Portland, Oregon, was chaired by Jim Ruff of NMFS and facilitated by Donna Silverberg. The meeting agenda and a list of attendees are attached as Enclosures A and B.

The following is a distillation (not a verbatim transcript) of items discussed at the meeting, together with actions taken on those items. Please note that some enclosures referenced in the body of the text may be too lengthy to attach; all enclosures referenced are available upon request from NMFS's Kathy Ceballos at 503/230-5420 or via email at [kathy.ceballos@noaa.gov](mailto:kathy.ceballos@noaa.gov).

Silverberg welcomed everyone to the meeting, led a round of introductions and a review of the agenda.

## ***II. Updates.***

***A. In-Season Management (TMT).*** Cathy Hlebechuk of the Corps updated the IT on current system conditions – reservoir storage, river flows, spill, water quality and the status of the juvenile migration. She noted that Dworshak continues to release 13.8 Kcfs, with TDG levels below the 110% Idaho gas standard. Hlebechuk added that, at this rate of discharge, there will be nearly 200 kaf left in Dworshak above elevation 1520 for release in September, an operation the tribes, in particular, have wanted to see for some years. Lower Snake River water temperatures continue to be surprisingly low for this time of year – 68 degrees in the Lower Granite tailrace, 70 degrees in the forebay.

Libby is releasing 17 Kcfs, Hlebechuk said, and the project is now forecast to end August at elevation 2442 feet, three feet above the elevation called for in the BiOp, thanks to a Libby/Duncan swap that is being negotiated with B.C. Hydro. Jim Litchfield said there is considerable pressure, within Montana, to reduce Libby outflow further; he said he will likely be submitting an SOR to that effect at next week's TMT meeting. Ron Boyce cautioned that Lower Columbia flows are already much lower than the salmon managers would prefer to see; according to the current SSARR, the summer seasonal average flow at McNary is only expected to be 192 Kcfs, which is below the BiOp flow target of 200 Kcfs. With both Dworshak and Libby expected to end August above their BiOp elevation targets, he said, the salmon managers are not likely to support any operation that further reduces lower river flows. NMFS is also concerned, said Ruff.

Full transport started at McNary on July 12, said Hlebechuk; transport is continuing every other day, and the current estimate is that only 25% of the run will be transported this year. The TMT has also developed a 2002 emergency priorities list for use by the action agencies, she added. Hlebechuk also touched briefly on the 2002 spill test at Libby Dam, noting that a report on that operation should be available soon; she also mentioned that development of the 2003 Water Management Plan is on track to produce a final document by the end of September.

**B. Independent Scientific Advisory Board (ISAB).** No ISAB report was presented at today's meeting.

**C. Water Quality Team (WQT).** WQT Chair Mark Schneider said that, while the WQT hasn't met in July and August due to scheduling conflicts, the WQT's RPA #143 subgroup has been quite active developing the plan for monitoring and evaluating available models for use in modeling Lower Snake River water temperatures. The subgroup has expanded the language of RPA #143 into a question matrix; once those questions are answered, said Schneider, we feel we will have addressed this RPA and provided the region with a useful management tool.

There has been extensive physical monitoring and biological study work ongoing in the Lower Snake this year, said Schneider, much more than in years past. This work will provide us with some data we haven't had in the past, at a time when we really need it to feed into the model that is ultimately selected to address RPA #143.

Last Monday, he said, we met with Idaho Power Company staff to talk about their monitoring work at the Hells Canyon Complex, and the effects of that project on water temperatures downstream. Between that data and the information we're getting from Dworshak this year, Schneider said, we should be able to put together a very useful model for managing the thermal regime in the Lower Snake. Schneider added that the subgroup is developing a draft report, which will be available for IT review some time in September.

**D. System Configuration Team (SCT).** SCT Chair Bill Hevlin described the current status of the FY'03 CRFM appropriations process, noting that, while the President's budget

requested \$98 million for the program, the Senate is recommending only \$87 in FY'03 CRFM funding, the House, \$85 million. Hevlin reported on the Corps' partially-successful efforts to restore the savings and slippage withheld from the FY'02 CRFM appropriation (about half of the savings and slippage has been restored, and the rest is expected to arrive before the end of the fiscal year). Hevlin said the SCT is in the process of revising the FY'03 CRFM program, attempting to reach consensus on a package of highest-priority measures that can be implemented within the anticipated \$85 million-\$87 million funding level. There are currently about 80 items on the CRFM measures worksheet, Hevlin said; the total cost, if all were implemented, would be \$110 million, so obviously, there is some work to be done there.

Moving on, Hevlin said the preliminary results from 2002 Lower Granite removable spillway weir test are now available; while there is still considerable data to be analyzed, the initial reports are that the RSW was very effective in passing fish. Hevlin said that as soon as the written report on the 2002 RSW test is available, he will provide a further update, perhaps at the IT's October meeting. Hevlin added that not only does the RSW pass fish effectively, it also passed floating debris and even dead cows without negative effects to juvenile passage.

Hevlin said the Lower Monumental stilling basin repairs are proceeding on schedule; the next step is for the contractor to drill nearly 600 holes into the bedrock as anchor points for the new concrete. The concrete will be poured underwater on November 15. End-bay deflectors will also be installed at Lower Monumental during this year's in-water work window, Hevlin added.

***E. TMDL Update.*** No TMDL update was presented at today's meeting.

***F. Water Quality Plan Work Group.*** Ruff reminded the IT that the Water Quality Plan work group was formed in response to the BiOp' Appendix B, which calls for the development of a mainstem Water Quality Plan. That work group has now met three times, and has undertaken a review of the six water quality projects identified in the Northwest Power Planning Council's mainstem/systemwide provincial review process. Some of those projects are ongoing, said Ruff, and some are new. Given the tight funding situation in the province, the prospects for funding any new projects are unknown at this time; however, we will be looking at those projects again at the next work group meeting on August 9, Ruff said.

In response to a question, Ruff said the geographic scope of the work group's planning effort is the entire mainstem, from the Hells Canyon Complex down to the Snake's confluence with the Columbia, and from the Canadian border to the mouth of the Columbia. Over the longer term, he said, we will be developing a mainstem water quality plan focused on water temperature and gas. We currently have an outline of that plan, Ruff added. We have also added a section to the outline dealing with other contaminants, including pesticides, he said; we have also developed a set of principles and a purpose statement. The next step is to start developing the plan itself, said Ruff; at the next work group meeting, we'll be talking about how to do that, and who is going to take the lead. We are going to include both ESA and Clean Water Act water quality actions in the plan, he added.

### ***III. Mainstem/Systemwide Provincial Review Process.***

Tom Iverson said the mainstem/systemwide project presentations were made to the ISRP and others two weeks ago; he distributed the most recent schedule for the rolling provincial review process. Since then, the ISRP has been drafting their preliminary review of proposals, Iverson said; that will be available for review tomorrow. We were somewhat surprised to hear that NMFS and BPA are conducting their own review of RM&E projects, Iverson said; their report was issued last week. We have been struggling to decide how best to fit the NMFS/BPA comments into the process such that they enhance, rather than muddy, it, Iverson said. Howard Schaller said the Fish and Wildlife Service was somewhat surprised that they had not been asked to participate in the NMFS/BPA comment process.

With respect to the next steps in the rolling provincial review process, Iverson reiterated that the ISRP will release its preliminary review this Friday; they are also expected to provide a response to the BPA/NMFS comments, he said. The project sponsors will then have two weeks to respond to the comments of both the ISRP and the RM&E work group, said Iverson. On August 23, we will then see the final proposals, he said. At that time, we will send those proposals out to CBFWA members for final review, Iverson said; in September, we will be doing the CBFWA review. He noted that the action agencies are invited to attend and participate in the CBFWA review process, although only CBFWA members will be allowed to vote on projects. The RM&E projects are expected to be discussed on September 9-11.

Once the review process is complete, the projects will go through the CBFWA approval process, Iverson said. The ISRP will then get a final look at the sponsors' responses to the preliminary ISRP and RM&E workgroup comments; the CBFWA workplan will be issued, and the ISRP will release their final comments, Iverson said.

In response to a question from Ruff, Iverson said \$77 million in mainstem/systemwide projects have been proposed; the available budget is \$35 million. Ongoing projects total \$44 million, he said, so you can do the math – it's going to be a struggle to keep at least some of the ongoing projects going, and to fund the new projects that need to get underway.

### ***IV. BPA Customer Presentation on A Proposal to Restructure BPA's Role in Power Supply Contracts.***

Jim Litchfield said Bonneville's customers have developed a proposal to restructure BPA's role in power supply contracts. As many of you have heard, he said, the Power Planning Council and Bonneville are beginning a process to review that and other alternatives for Bonneville's role in the future. Litchfield introduced Scott Brattebo of PacifiCorp, who provided an overview of the customers' proposal.

Brattebo began by saying that Bonneville concluded its most recent subscription process in 2000; that process was followed by a fair amount of litigation against the Bonneville Power

Administration, Brattebo said. Those lawsuits were focused primarily on the benefits that the investor-owned utility residential and small farm customers are receiving.

With all of this outstanding litigation potentially threatening the subscription process, he continued, a number of Bonneville customers -- both investor-owned and public utilities -- came together to develop a proposal for settling this outstanding litigation, as well as a long-term plan for how the benefits of the Federal Columbia River Power System should be divided up. Our thought was that if we could develop a joint proposal, we might have a chance of bringing the rest of the region -- the Direct Service Industries, the conservation and renewables groups, fish and wildlife groups and Bonneville -- on board, Brattebo said.

Back in April, we released a settlement proposal that addressed the interests of investor-owned and public utilities, Brattebo continued. This proposal did not address the interests of the DSIs, the conservation and renewables groups or those of many other parties in the region. Essentially, we were trying to decide, for a period of at least 20 years, what the public utilities' rights were with respect to power allocations, as well as what the investor-owned utilities' residential and small farm customers' rights would be.

With respect to the specifics of the proposal, Brattebo said the investor-owned utilities would receive a financial package, because the FCRPS does not produce enough power to serve both the public utilities and the residential and small farm customers of investor-owned utilities. Keeping with tradition, he said, we put together a package under which our customers would receive some financial benefits, in the form of billing credits. Brattebo went through the details of these proposed financial benefits; in general, he said, our goal was to reach a new settlement that would provide a benefit to all of the investor-owned utilities' residential and small farm customers. Brattebo noted that, in the past, Avista's, Idaho Power's and Montana Power's customers never received anything. Under this new plan, their customers would receive the same financial benefits as PacifiCorp's and PGE's customers have traditionally received.

With respect to what the public utilities would receive from the settlement proposal, Brattebo said they would have access to two different types of products. The first is requirements service, under which Bonneville would shape load to take care of the public utilities' power needs. The other product public utilities want access to is called SLICE, a key element of the agreement. Essentially, what we're hoping is that the majority of the FCRPS output -- 5,000 aMW -- would be sold through SLICE, while about 2,000 aMW would be sold through requirements service, Brattebo said.

Our goal is to get Bonneville out of the power market, he said, because BPA is in the market for three different reasons -- first, when they shape the system to meet the customers' load, second, to sell any surplus energy they may have, and third, augmentation, when the system doesn't produce enough energy to serve load on an annual basis.

The latter area is what has gotten Bonneville into trouble, Brattebo said, because on

average, the system comes up about 3,000 aMW short. As a result, he said, Bonneville has had to acquire a significant amount of energy on the open market, and we all know what has happened to Bonneville's rates as a result. Our goal in the future is to move the responsibility for both load growth and shaping the system to the individual utilities, Brattebo said. Brattebo added that the anticipated term of the contract would be 20 years; during the term of that contract customers, in exchange for the benefits of the SLICE program, would agree not to ask Bonneville to add capacity to serve their load – instead, SLICE customers would have to find their own resources.

Brattebo, with the help of other members of the proposal development team, continued on through the details of the proposal, explaining the specifics of how the power and financial benefits of the FCRPS would be allocated among the various regional entities and their customers. They touched on the role of SLICE, the definition of “shaping” within the proposal language, the apparent negative impact of Bonneville's power sales and purchases on the overall West Coast energy marketplace, and the role of traditional requirements service in the proposal.

In response to a question, Brattebo said that, under the proposal, the flow regime in the system would not change, because SLICE customers would receive the benefits of whatever flows come down the river, seasonally – they would have excess capacity to sell during the spring, when loads are relatively low and flows are at their peak, and would likely have to buy energy during the winter, when Northwest loads are at their peak but river flows are lower. Basically, said one utility participant, under this proposal, from a river operations perspective, we don't see anything that would change. What you're saying, then, is that non-power requirements, such as fish operations, recreation and flood control, are built in, and come off the top? Ruff asked. That's correct, was the reply.

The discussion turned to the historic load assumptions underlying the customer proposal; Howard Schaller noted that those assumptions are critical to determining the constraints imposed by energy needs on non-power operations. Historic load is a very small piece of the overall proposal, replied Lyn Williams of PGE; SLICE isn't based on any sort of load, it's based on what the system puts out. What the utilities look at is the 60-year historic water record and the current BiOp fish operational requirements, added Litchfield. The current estimate is that the FCRPS can produce about 7,000 a MW in firm energy during a critical water year such as 2001; that energy comes out in a different shape every year, depending on the shape of the runoff. What they are slicing up is that 7,000 aMW, he explained, after providing fish operations.

The discussion turned to the specific benefits Bonneville's customers would derive from this proposal. Litchfield explained that the customers feel that they pay Bonneville's costs in any event; what this proposal would give customers is more control over what market purchases are made. Basically, he said, the utilities aren't happy with the fact that Bonneville makes all of those marketing decisions, currently; they would prefer to take more responsibility for those decisions, and pay the price for any mistakes that might be made. In response to another question, Litchfield explained that SLICE is an agreement under which, in exchange for X% of

the energy produced by the system, Bonneville's customers agree to pay X% of the costs.

Essentially, he continued, under this agreement, Bonneville's Treasury repayment becomes much more secure, because the customers are willing to pay a percentage of Bonneville's total revenue requirement; when you combine that with the fact that Bonneville no longer has to make large market purchases, that is a significant transfer of risk from Bonneville to its customers. Brattebo added that, in future years, if this proposal is accepted, Bonneville will not find itself in the type of financial straits it is currently experiencing, because under this agreement, we will pay their costs, whatever they are – the money will be there.

Another participant noted that one of the reasons Bonneville is in its current financial situation is that, because of the way the rate case process works, Bonneville is forced to base its rate structure and power sales contracts on forecasted load and energy price estimates. This isn't a knock on Bonneville, she said, but if there is one thing we all know about forecasts, it is that they are going to be wrong, by a small margin or a large one. This proposal takes that forecasting risk away from Bonneville and divides it up among the utilities.

Brattebo added that another reason Bonneville's customers have developed this proposal is that it represents a coalition of Northwest interests, united in an attempt to defend the FCRPS against outside influences in the Northeast, the Midwest and elsewhere, who want to take that system away from us. We're working together to try to preserve the benefits of the FCRPS for the Northwest, he said. Litchfield added that copies of the proposal are available from him or from Brattebo upon request.

What do the DSIs think about this proposal? Ruff asked. It depends on which DSI you ask, Brattebo replied, and what they're getting from the proposal. Litchfield noted that negotiations with various DSIs are ongoing; we are confident that we can reach agreement with at least some of them, he said. In other words, the DSIs will be worked individually into the agreement, depending on their situations? Ruff asked. That's correct, Litchfield replied -- we're still talking with the DSIs.

My main question has to do with an earlier statement, to the effect that the current rate case structure pits one utility group against another, and the fact that if one wins, another loses, said Ruff. Under the current arrangement, in the fish and wildlife community, when we make a System Operational Request, or request funding for a fish and wildlife-related capital improvement project, if that request is turned down, we know who to go to -- Bonneville or the Corps, Ruff said. Our fear is that, with the latest pressure to hold costs down, if this proposal is implemented, we will then be under pressure from all of the utility interests in the region to hold costs down as well, and to manage the system with economy foremost in mind. The Fish & Wildlife community does want to make the actions and measures we recommend as efficient and cost-effective as possible, said Ruff, but we aren't going to endorse a system under which those already-heavy financial pressures are intensified by more entities.

Litchfield replied that Bonneville's customers already apply pressure to ensure that fish costs are as low as possible; that's one of the reasons TMT meetings are packed not only with action agency and salmon manager representatives, but with power marketers as well, he said. One thing that could really help, however, is that much of the current environment is driven by Bonneville's need to be in the market to meet utility demand, Litchfield said. When Bonneville has to raise rates, participate heavily in the marketplace and therefore runs into cash flow problems, that causes destabilization, and that's when fish really suffer, he said. When you take the power market risk off of Bonneville and put it onto the utilities' shoulders, that will make Bonneville more financially stable, said Litchfield.

Ruff noted that, as the IT heard this morning, the mainstem/systemwide rolling provincial review process has resulted in \$77 million worth of project proposals. We also heard that there are \$44 million in ongoing projects, and only \$35 million in available funding for that province. That means that, come the three- and five-year check-ins called for in the BiOp, many of those projects will likely not have been implemented, said Ruff, so what we're wondering is, did you assume, for the purposes of this agreement, that fish and wildlife costs will remain constant, and will not increase?

Absolutely not, Litchfield replied – Bonneville estimated its fish and wildlife-related costs during the 2001 drought year at \$1.7 billion, most of which was in the form of market exposure. In other words, said Litchfield, another \$30 million to implement projects in the mainstem/systemwide province is really just background noise in the larger scheme of things. One of the main goals of this proposal is to fix that problem, added Rob Walton – if Bonneville isn't having to go to the market and spend over a billion dollars on power purchases the next time there is a drought, that's only going to help matters for fish. If the utility proposal fixes Bonneville's exposure to the market, the result will be less pressure to keep fish costs down, Walton said.

Ron Boyce said the salmon managers are already concerned that the hard constraints in place on the system for fish operations and for adequate fish and wildlife program funding are already being violated; every time we turn around, he said, we see BiOp operations being reduced, and now Bonneville is talking about deleting \$30 million from the \$186 million in annual direct program funding that we thought was secure. We are very concerned about the potential for the utility proposal to bring about further deterioration in the region's fish and wildlife funding situation, Boyce said.

Bonneville wouldn't be making those cuts if it weren't for their financial condition, replied Brattebo; again, one of the main goals of this proposal is to restore Bonneville's financial stability by reducing its exposure in the energy marketplace, and by providing assurance that the cost of operating the power system will be met.

One key point to take away, said Litchfield – SLICE customers would agree to pay a percentage of Bonneville's costs in exchange for a percentage of the federal power system's

output; that would result in a contractual arrangement that doesn't require Bonneville to maintain a large financial reserve. In other words, the more the system moves toward SLICE, the less Bonneville's reserves become an issue that impacts fish and wildlife expenditures, he said.

Litchfield noted that, in mid-to-late September, Bonneville and the Northwest Power Planning Council will begin a public process that will include a series of public meetings throughout the Northwest to discuss the Bonneville customers' proposal; in mid-October, Bonneville will then prepare its own proposal, in response to the customers' proposal. Bonneville's proposal will then be presented to the region in the form of a draft Record of Decision, Litchfield said. By next April, Bonneville will take the comments received on its draft ROD and develop a final Record of Decision, from which will flow power sales contracts to be offered to Bonneville's customers. Those contracts will then be signed in the winter of 2003, or perhaps early in 2004, said Litchfield.

Ruff thanked all of the participants for their input into this complex agenda item; it is an issue of great interest to the IT, and we hope to continue this dialogue as the public process progresses and more written proposals are presented, he said. I had two further questions, however: first, how this proposal will take into account continued funding for conservation and renewables, and second, exactly how you think the proposal would affect BPA as an institution, Ruff said.

I suspect there will be a fair amount of change within Bonneville, but not much change that would be noticeable from the outside, Brattebo replied. They have a fairly large trading floor, currently, which is responsible for buying and selling in the energy marketplace; obviously that activity would be reduced under this proposal. Beyond that, I don't see a lot of changes occurring within the organization, other than the fact that SLICE management would need to be stepped up, he said.

Litchfield noted that there seems to be some feeling, within the region, that this proposal is an outgrowth of a feeling that Bonneville has done a poor job in the energy marketplace. That is not our intent at all, he said – this proposal has arisen from the fact that, if they're paying the bills anyway, Bonneville's customers would like more responsibility for making power marketing decisions. Frankly, he said, the last year wasn't pretty for anyone in the Northwest power industry, including the public utility districts and the IOUs. What we're proposing is a more mature, less-paternalistic relationship between Bonneville and its customers, Litchfield said.

With respect to the conservation and renewables question, said Williams, we have been talking with some of the environmental groups and others in the region with an interest in this topic. We initially included in the proposal some placeholder principles stating that conservation and renewable funding would be increased and stabilized. The conservation and renewables parties are now drafting a piece to insert in our proposal that meets their needs, she said, and our hope is that we can just insert that section into the final draft.

## ***V. NMFS Findings Letter.***

Chris Toole of NMFS began by saying that a variety of documents relating to the NMFS findings letter, including a summary of NMFS' findings for the 2002 Implementation Plan, a summary of the RPA actions requiring modification resolution, and an extensive document listing 2003-2007 project deliverables by strategy and sub-strategy are now available via the NMFS website or by accessing the salmonrecovery.gov website or by calling Kathy Ceballos 503/230-5420.

Of most interest to this group would be the hydro actions, said Ruff. That is probably true, said Litchfield, but my clients are most interested in what happens from here – at the three-year check-in point, for example. Under the 2000 BiOp, each year, the action agencies prepare a one-year and a five-year plan, Toole replied; in 2003, 2005 and 2008, there is a comprehensive review, and a decision point. The way the off-years are characterized in the decision guide is that this isn't a report card, it is a mid-term grade – are we on track or not, and does it look like our goals for 2003 will be met. Our goal is to find out if we're off-track or behind schedule on any of the RPAs called for under the BiOp. Toole explained.

In many cases, there is a good reason for the changes to the BiOp implementation schedule, Toole said, and it may represent an improvement over what we anticipated in the BiOp. In those cases, he said, we need to document that and give NMFS' seal of approval – there are 16 actions in the findings letter that fall under that category. The other point is that if we have a modification that is a concern, we want to identify it, and figure out what the action agencies and NMFS are going to do about it during the next year, Toole said. He clarified that what he means by a "concern" is that the action agencies and NMFS have restricted themselves, during this review, to what will pass muster during the 2003 review – we have no practical way of reviewing what actions will pass muster during the 2005 review, he said.

Basically, NMFS is looking to implement enough actions in FY'03 to get the specifics of what we're looking for in Appendix F of the 2003 BiOp rolling, Toole said. That includes specific actions associated with about two-thirds of the RPAs laid out in the BiOp, he said. Essentially, we want to highlight the projects, in our findings letter, that could influence the FY'03 actions we all need to consider, Toole said.

Palensky observed that while the NMFS' findings letter is not up for comment, it is directly related to the draft Implementation Plan, which NMFS, at least, would like to comment on. In response to a question about the timing of the 2003 check-in, Toole said his understanding is that the Action Agencies' draft 2003-2007 Implementation Plan is now available. We have said for this year's review that we need to have the progress report for 2002, the proposal for the coming year, and the five-year plan as soon as possible, Toole replied. Apparently, the five-year plan will not be available until the spring of 2003, so we will do without it, he said. The final 2003 Implementation Plan is expected to be available in September, and NMFS will prepare its final report on the FY'03 annual plan 45 days after it is received. We will then start the process

that will produce the draft 2003 check-in progress report by September 2003, Toole said, with the final findings letter to follow within a month or two.

In response to a question, Toole said funding, coordination and disagreement about the goals among the federal agencies are still issues with respect to the 2003 check-in point. What can IT do to assist this process? Silverberg asked. Even though we're not asking for comments, Toole replied, we will be turning around within three months and starting to write our next findings letter. One of the things that will be included is the summary of what the action agencies are proposing to do over the next fiscal year, as well as what everyone else is proposing to do. If there are disagreements about how we have characterized things, said Ruff, while we're not looking for comments at this point, if you think we've done something wrong, we'd like to hear it.

#### ***VI. Status of FY'03 Implementation Plan.***

The Action Agency draft 2003/2003-2007 Implementation Plan for the FCRPS was distributed at today's meeting.

#### ***VII. Report on BPA "Financial Choices" Process.***

Suzanne Cooper of Bonneville led this presentation. As you have already heard today, she said, Bonneville set its power rates for the period FY'02-FY'06 last year. Our financial condition has deteriorated since we set those rates, Cooper said. While the new rate structure has some mechanisms embedded, called cost recovery adjustment clauses (CRAC), which allow Bonneville to adjust its rates to recover costs, our current analysis shows that, over the current rate case period, we will still be 5%-6% short in revenues vs. projected expenses.

With that in mind, in early July, BPA Administrator Stephen Wright sent out a letter and information packet (Enclosure E), Cooper said. This packet includes the Administrator's letter, an overview of the situation Bonneville is facing, and a letter from Paul Norman, Senior Vice President of Bonneville's Power Business Line, providing more detail about Bonneville's financial situation and laying out more options about the key questions and policy choices facing Bonneville. A third handout (also included in Enclosure E) details the public meetings schedule associated with Bonneville's Financial and Program Options public process:

Portland: August 15, 2002, 1-4 p.m. at the Sheraton Hotel Portland Airport

Portland: August 15, 2002, 6-9 p.m., BPA Headquarters

Seattle: August 20, 2002, 1-4 p.m., Hilton Hotel, Sea-Tac Airport

Seattle: August 20, 2002, 6-9 p.m., Mountaineers Headquarters, Pinnacle Room, 300 Third Ave. W.

Spokane: August 21, 2002, 1-4 p.m., Ramada Inn, Spokane Airport

Burley, Idaho: August 28, 2002, 1-4 p.m., United Electric Co-op Inc.

Cooper described some of the factors contributing to Bonneville's current financial situation. Basically, she said, I wanted to inform this group that there is a public process ongoing to take the input from a variety of stakeholders about that situation, and how they would prefer to see Bonneville resolve it. That public process will be ongoing through the end of September; at that point, we will assess the input received, then develop a financial plan that will address our future needs, Cooper said.

In response to a question from John Palensky, Cooper said this process is in response to a shortfall between Bonneville's expected revenues during the rate period (FY'02-FY'06) and expenses. Basically, she said, expenses over the rate period are higher than anticipated, while revenues are lower. There is no opportunity to recover without raising rates, in terms of lower-than-anticipated energy costs for Bonneville's contractual obligations over the rate period? Palensky asked. Obviously you're in the first year of this rate period, and you're always going to be off in your forecasts, Palensky said – isn't there an opportunity for Bonneville to make a recovery over the period of the rate case without raising its rates? No, not without raising rates, Cooper replied – the details are laid out in (Enclosure E).

Cooper went through the specifics of the financial options Bonneville is considering:

- Simply let the established rate mechanisms (LB, FB and SN CRAC) play out over the next four years (which includes cost cuts and capital and expense reductions already in place).
- Cut more costs (both capital and expense) down to levels that put mission accomplishments at risk and raising rates, as necessary, to cover the remaining gap.
- Take more risk in repaying the Treasury (no SN CRAC).
- Use financial tools to manage net revenue and cash shortfalls and to push the financial problem into the future.
- Make a one-time adjustment to FY'03-06 rates through the SN CRAC to achieve a five-year 80 percent TPP, then applying no further FB or SN CRAC adjustments, potentially combined with using cash tools to increase FY'03 TPP.

We are asking the region to weigh in on how we should solve this problem, Cooper said. She answered a variety of clarifying questions and comments regarding BPA's public "Financial Choices" process.

So essentially, the point for today is that these public meetings are coming up, and Bonneville welcomes the input of all regional stakeholders, obviously including those at IT, for the choices it is facing, Silverberg observed. That's correct, Cooper replied.

The group discussed the nuances of the fish and wildlife financing and crediting arrangements that could result from this process, including the Bonneville direct program, capital and interest payments, and the role of CRFM funding. Ultimately, Silverberg asked what the

next IT action on this item should be; it was agreed that Bonneville will provide a further update at the IT's September meeting, once the August public meeting sequence concludes.

***VIII. Next IT Meeting Date.***

The next Implementation Team meeting was set for Thursday, September 5 at the Grand Coulee Dam office in Grand Coulee, Washington. Ruff noted that a tour of FDR Lake and a discussion of its fishery and cultural resources of particular importance to the area tribes was scheduled to depart at 10:30 a.m. on Wednesday, September 4. Meeting summary prepared by Jeff Kuechle, BPA contractor.